Status of NYISO Demand Response Programs

February 9, 2004

Price Responsive Load Working Group

EDRP/SCR Registration by Zone

EDRP/SCR Registration as of 2/6/2004				
Zone	SCR Sold		EDRP Registered	
	MW Sold	# Customers Registered	MW Registered	# Customers Registered
A	293	38	54	55
B	28	18	32	15
C	90	35	39	155
D	159	5	5	9
E	13	11	57	53
F	53	14	65	62
G	0	0	55	41
H	1	1	7	9
I	3	5	15	28
J	149	76	134	127
K	10	24	182	815
TOTAL	799	227	645	1369
TOTAL EDRP & SCR	1,444	MW	1,596	Customers

RIP and CSP Total MW Registered

EDRP/SCR Breakdown Effective February 6, 2004

RIP/CSP/DRP Type	*EDRP/SCR MW*	*DADRP MW*
8 Aggregators	496.1 MW	21.5 MW
9 LSEs	230.7 MW	
5 Direct Customers	130.6 MW	276.4 MW
8 Transmission Owners	628.7 MW	50.6 MW

Final August EDRP/SCR Response by Zone

Zone	Total MW Registered	Curt Load or Both	DG	Average MW Response 15-Aug	Average MW Response 16-Aug	Average Performance 15-Aug	Average Performance 16-Aug
A	441.90	429.90	12.00	293.00	251.40	66.3%	56.9%
B	63.40	62.10	1.30	33.00	28.20	52.1%	44.5%
C	114.00	97.20	16.80	61.30	41.50	53.8%	36.4%
D	223.20	219.80	3.40	13.00	6.50	5.8%	2.9%
E	83.60	54.20	29.40	31.70	8.90	37.9%	10.6%
F	124.00	113.70	10.30	70.00	61.60	56.5%	49.7%
G	59.40	43.90	15.50	23.10	13.60	38.9%	22.9%
H	9.60	3.50	6.10	3.70	0.90	38.5%	9.4%
I	25.85	17.85	8.00	17.80	3.00	68.9%	11.6%
J	227.18	181.88	45.30	86.80	39.50	38.2%	17.4%
K	186.82	104.32	82.50	70.20	12.30	37.6%	6.6%
TOTAL	1,558.95	1,328.35	230.60	703.60	467.40	45.1%	30.0%

August 15 Payout:	$5,419,412.10
August 16 Payout:	$1,808,215.82
Total Payout:	$7,227,627.92

Average Performance SCR Resources	
15-Aug	16-Aug
51.77%	45.45%

Average Performance EDRP Resources	
15-Aug	16-Aug
49.77%	19.50%

Northeast ISOs DR Programs

Demand Response Program Implemented by Northeast Utilities - Summary of Provisions												
	NYISO				ISO-NE				PJM			
	Reliability Based		Price Based		Reliability Based		Price Based		Reliability Based		Price Based	
Program Name (1)	EMER	ICAP	DA	RT	EMER & ICAP		DA	RT	EMER	ICAP	DA	RT
	EDRP	*SCR*	*DADRP*	*None*	*RTDR (1)*	*Profile*	*none*	*RTPR*	*ELRP*	*ALM*	*ELRP-DA*	*ELRP-RT*
Customer Type I-Indiv, A-Aggreg,	I/A	I/A	I/A		I	A		I/A	I/A	I	I/A	I/A
Minimum Reduction (MW)	0.1	0.1	1		0.1	0.2		0.1	0.1	0.1	0.1	0.1
Events	Forecast or actual deficiency	Forecast or actual deficiency	When bid is scheduled day ahead		OP4 Res. Deficiency	OP4 Reserve deficiency		When LMP > $.10 forecast	Reserve Deficiency	Reserve Deficiency	Bid accepted	Customer indicates to PJM
Response Time (Hours)	2	2 hrs., after day-notice	by 1:00 a.m., with DA warning		Choice of 2 hr., 30-min.	2		Several hours to day ahead	1	1 & 2	24	1
Energy payment for kWh curtailed	Higher of $.50 or RT LBMP	LBMP	Day-ahead LBMP		$0.35 (2-hr) or $.50 (30-min)	Real-time LBMP		LBMP	Higher of $.50 or RT LBMP	none	Day-ahead LBMP	Real time LMP
Minimum Payment Rate ($/kWh)	$0.50	Higher of RT LBMP, Curtailment bid	Higher of Bid or day-ahead LBMP		none	$0.10		$0.10	$0.50	type of ALM (DLC, FSL or GLD)	LMP	LBMP less G&T charge
Minimum Duration of Event (Hours)	4	4	Greqter of 1 hr. or min. run time		2	2		1	2	1	1	1
Maximum Duration of Event (Hours)	24	24	8		11	11		11	24	6	24	24
Specific Event Limits	none	none	none		none	none		ISO must open response window	none	10 event/summer	none	none
Bid Limits	NA	$.50/kWh curtailment bid ceiling	$.05/kWh floor, $1.00 ceiling		NA	NA		none	NA	NA	$50	75, but subject to T&D deduction
ICAP Credit Yes/No	N	Y	N		Y	Y		N	N	Y	N	N
Program Start Date	5/01	11/99	5/01		3/03	3/03		03/03	6/02	1/03	6/02	6/02
Program End Date	10/31/05	none	10/31/04		2/06	2/06		2/06			12/04	12/04
Minimum Term (Yrs)	none	I month	none		1	1		1	1	none	na	na
Penalty (Yes/No)	N	Y	Y		Y	Y		N	Y	Y	Y	Y

Source: Neenan Associates and NERA, 2004, **The Role and Value of Demand Response Resources in a Central Resource Adequacy Model,** draft report prepared for PJM Interconnection on behalf of NYISO, ISO-NE, and PJM Interconnection.

Northeast ISOs DR Programs

An additional $3.4 Million paid to ICAP/SCRs in 2003

Summary of Demand Response Participation and Payments 2001 - 2003

	Registered Sites			MW			Payments		
	2001	2002	2003	2001	2002	2003	2001	2002	2003
Emergency									
ISO-NE	12	79	106	6	113	249	$380	$1,801,865	$497,076
NYISO	292	1535	1323	425	949	858	$4,200,000	$3,300,000	$3,900,000
PJM	17	61	99	62	39	629	$287,514	$282,765	$26,613
Subtotal	321	1675	1528	493	1101	1736	$4,487,894	$5,384,630	$4,423,689
Economic									
ISO-NE	89	146	332	57	75	130	$226,132	$172,046	$212,011
NYISO	16	24	27	8	393	411	$200,000	$100,000	$121,300
PJM	33	116	221	6	16	711	$13,994	$761,997	$678,220
Subtotal	138	286	580	71	484	1252	$440,126	$1,034,043	$1,011,531
ICAP									
NYISO SCR	209	225	213	342	659	850	Bilateral payments are not reported		
PJM ALM	864,861	911,403	851,120	1,962	1,292	1,207			
Subtotal	865,070	911,628	851,333	2,304	1,951	2,057			
Totals	865,529	913,589	853,441	2,868	3,536	5,045	$4,928,019	$6,418,673	$ 5,435,220

Source: Neenan Associates and NERA, 2004, **The Role and Value of Demand Response Resources in a Central Resource Adequacy Model,** draft report prepared for PJM Interconnection on behalf of NYISO, ISO-NE, and PJM Interconnection.

SCR Issues - Testing

- NYISO Conducted tests of SCR resources on January 27 (Zones H-G), 28 (Zone A), and 29 (Zones B-G)
- Tests were mandatory only for resources sold in January, other resources were invited to meet their testing requirements during this test
- Additional tests will be conducted in February and/or March
- These tests will be mandatory for resources sold in the current month and for resources sold for the Winter 2003-2003 strip, provided those resources did not test during January
- To prevent undue market impacts, future tests will generally be broken down into zonally-defined groups
- NYISO reserves the right to decide which zones to call and they may not necessarily be contiguous
- To the extent practicable, advance notice will be limited to that provided for during actual events (i.e. 21-hours)
- Zonally-defined SCR tests may take place in different weeks (as opposed to different days in the same week)
- Going forward, NYISO is considering running tests on a monthly basis (participation would only be mandatory for each resource once each capability period)

SCR Issues - Aggregation

- SCR program rules allow individual resources to be aggregated to achieve the 100 kW minimum, as well as for measuring performance for UCAP purposes
- SCR resources must be certified in 100 kW increments (i.e., 150 kW is rounded down to 100 kW), as has always been the case
- Currently several resources can be aggregated under one PTID for purposes of determining energy payments
- CHANGE — For the Summer 2004 capability period, each resource/meter must have its own unique PTID to facilitate auditing and avoid the possibility of double-counting
- Resources may still be aggregated for purposes of determining SCR performance under a “super-PTID” or other registration vehicle
- Procedures for registering and reporting aggregated SCR resources for 2004 will be determined and issued by the NYISO prior to start of the 2004 Summer capability period.
- SCR-related issues are appropriately addressed in the ICAP Working Group (next meeting is February 12, 2004)

SCR and EDRP – DG with Net Export

- Current EDRP and SCR rules prohibit DG from being paid for energy production in excess of host load and restrict SCR UCAP credit for directly metered generation to the host load
- The value to the NYISO of energy/capacity in excess of host load is the same as energy/capacity less than host load
- Should rules be modified to allow UCAP credit and energy payments for generation in excess of host load?

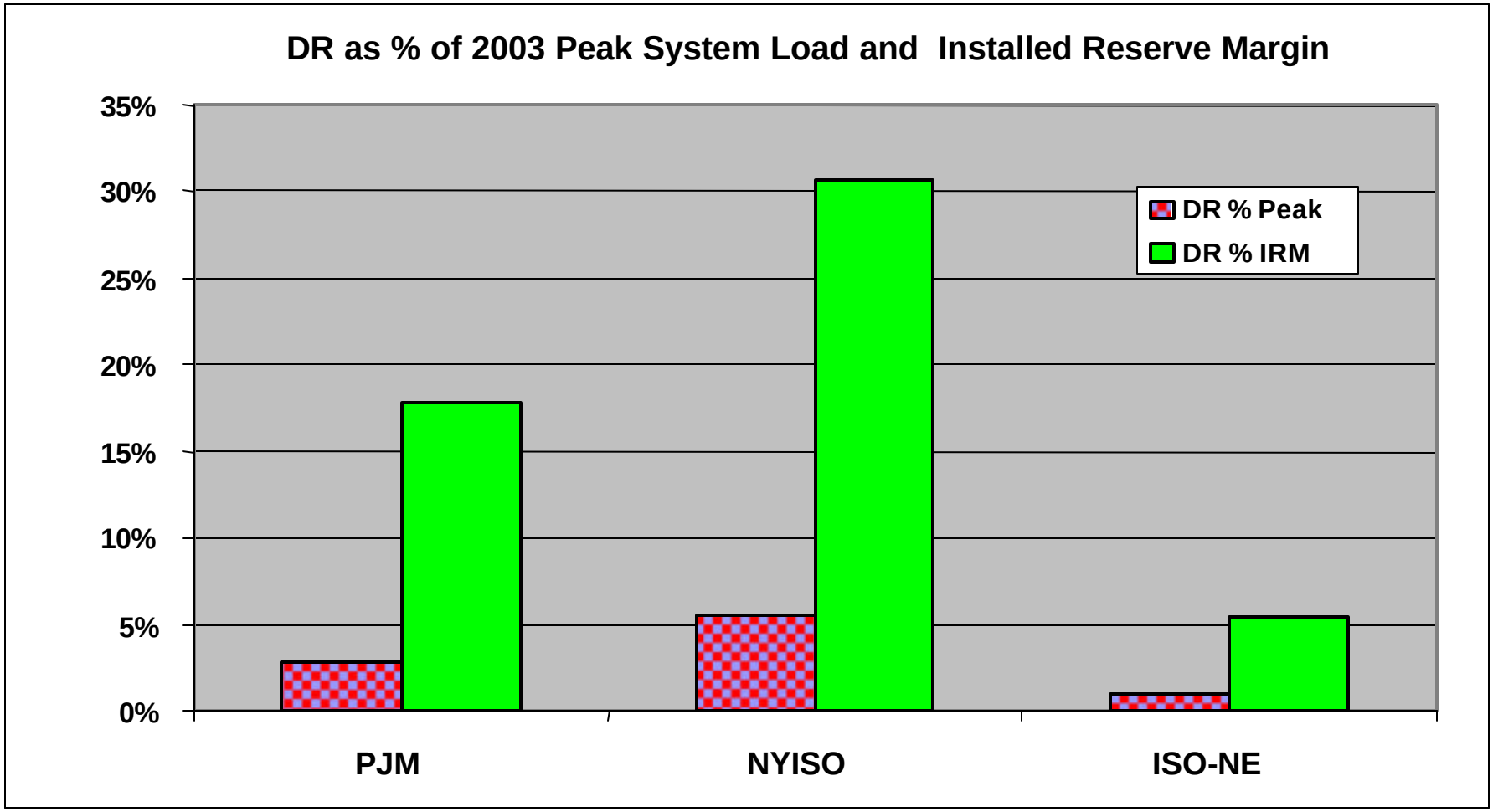
DADRP Issues - Background

At the December 16, 2003 meeting of the PJM Demand Side Response Working Group Alison Silverstein, Senior Policy Advisor to FERC Chairman Pat Wood III advised:

- FERC wants demand response “no matter what”.
- FERC is not kidding and would rather we make demand response happen by sending up good, tough programs and good, strong, solid filings, instead of making them do it to (PJM)
- FERC expects to see a credible set of programs filed. They expect that those programs will reflect not just going through the motions and giving FERC lip service but coming through with big time programs that get big time results and are very high quality.
- FERC advised PJM not to starve DR programs, pointing out that the programs do not get rate-based returns or tax credits. They note that these programs are in their infancy and need time to grow.
- FERC advises us to not keep changing the rules, suggesting that DR and DG need stability and security, education and ramp up time.

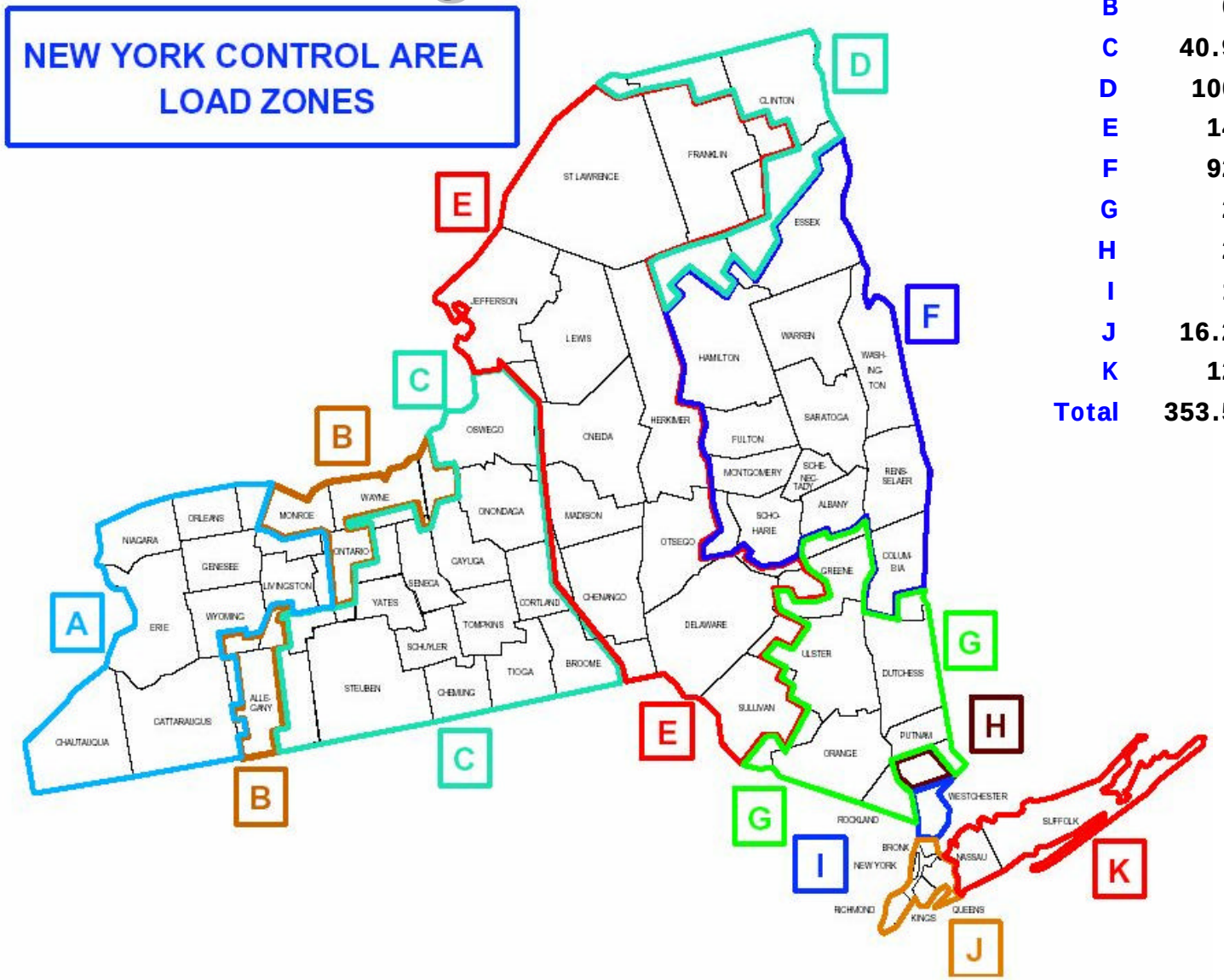
“Competition is not going to work if it is one sided, supplier-on-supplier only. Real competition will only work if it is meaningful supply competition against meaningful demand competition.”

Relative Demand Response Penetration Levels



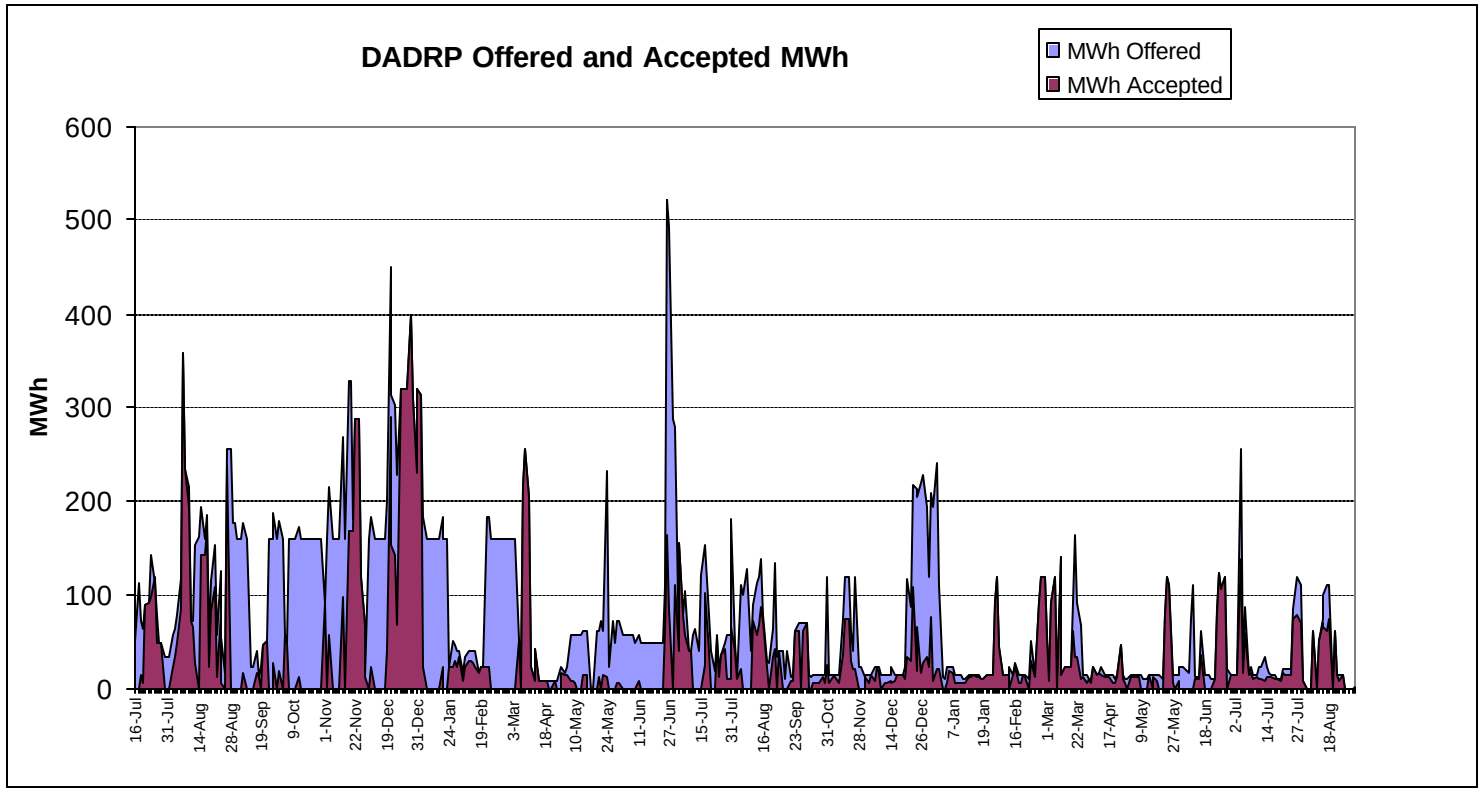
Source: Neenan Associates and NERA, 2004, **The Role and Value of Demand Response Resources in a Central Resource Adequacy Model,** draft report prepared for PJM Interconnection on behalf of NYISO, ISO-NE, and PJM Interconnection.

DADRP Registration



Zone	MW
A	73.4
B	0
C	40.9
D	100
E	14
F	92
G	2
H	2
I	1
J	16.2
K	12
Total	353.5

DADRP Performance



DRAFT – For Discussion Purposes Only

DADRP - Background

- New York's Emergency Programs (EDRP and SCR) are arguably the most successful in the nation and the world
- New York's Economic Demand Response programs have significant registration, but very little regular participation
- FERC clearly wants to see robust economic (and emergency) demand response programs implemented

DADRP – Obstacles (Real and Perceived)

- Lack of program certainty – incentive expires 10/31/2004. One year extensions have been the norm since inception
- 1 MW minimum bid effectively excludes small participants
- Settling deviations at the higher of DA or RT price imposes a potentially significant penalty for non-performance that does not apply to generators
- Requirement that third-party DRPs be MDSPs to submit meter data and MSPs to read meters is problematic given PSC's unwillingness to certify end-users
- Inability to Accept Meter Data from non-TOs has hampered timely payment
- Complex bidding requirements confuse all but the most sophisticated end-users
- Too many choices, too little useful information makes constructing a useful bid difficult for customers
- Low awareness of DADRP. Most end-users don't even know about the program
- Inadequate payment/incentives/low prices cited as barriers
- $50/MWh bid floor price is too high and prevents low-cost resources from participating

DADRP - Recommendations

NYISO-Proposed Changes

- Make the DADRP program permanent
- Eliminate the Incentive by revising the program to eliminate the aspect of the program that credits a participant's LSE with DADRP accepted schedule, consistent with the non-incentivized recommendation developed at PRLWG in 2003. No more "double payment"
- Amend the DADRP so as to settle deviations from Day-Ahead schedules at the RT LBMP, consistent with other NYISO markets
  - DRPs would be paid the DA LBMP for accepted schedules and would settle deviations from those schedules at the RT LBMP.
- Remove the requirement that PSC-certified MSP/MDSPs submit meter data. DRPs must identify TO/MDSP supplying data, and the NYISO would retain ability to audit meter data.
- Allow participation by adequately permitted, small, inside-the-fence generators
- Increase the bid floor to $75/MWh
- Begin to explore the desirability and feasibility of a non-incentivized Real-Time Demand Response Program that allows DR to participate in both the energy and ancillary service markets on a non-incentivized basis

Payment Stream under Proposed Approach

	Day Ahead	Real Time	
LBMP $_{bus}$	**$250**	**$300**	assumed
LBMP $_{zonal}$	**$250**	**$300**	assumed
Fixed Load (MW)	**100**	**99**	Real time fixed load is metered load plus measured curtailment.
Load Reduction (MW)	**10**	**7**	Measured performance by DRP
Total DAM Load (MW)	**90**	**92**	Real time net load appearing on meters.
Shutdown duration (hrs)	**1**	**1**	assumed

	LSE/LDC with no DADRP	Separate DRP and LSE				
Day-Ahead Settlement	**LSE**	**DRP**	**LSE**	**GEN**	**NYISO**	
Day-Ahead Energy Purchase	-$25,000	$2,500	-$25,000	$22,500	$0	DRP credited with day-ahead load reduction
Real-Time Settlement						
Real Time Reconciliation	$300	-$900	$300	$600	$0	LSE needs a real time correction if RT fixed load (meter read plus DRP performance) exceeds DA fixed load. Real time correction is provided by generators. Non-performance is made up by generators in real time, and paid for by DRP.
Total Wholesale Billing	**-$24,700**	**$1,600**	**-$24,700**	**$23,100**	**$0**	

Payment Stream under Proposed Approach

	Day Ahead	Real Time	
LBMP $_{bus}$	**$250**	**$300**	assumed
LBMP $_{zonal}$	**$250**	**$300**	assumed
Fixed Load (MW)only	**100**	**99**	Real time fixed load is metered load plus measured DRP reduction
Load Reduction (MW)	**10**	**7**	Measured performance by DRP
Total DAM Load (MW)	**90**	**92**	Real time net load appearing on meters.
Shutdown duration (hrs)	**1**	**1**	assumed

	current method	*new method to be implemented*					
			Separate DRP, LDC and ESCO				
	LSE w/ DADRP						
Day-Ahead Settlement	**LSE**	**DRP**	**LSE**	**LDC**	**GEN**	**NYISO**	
Day-Ahead Energy Purchase	-$25,000		-$25,000		$22,500	$2,500	LSE buys fixe
Incentive Credit	$2,500		$2,500			-$2,500	LSE gets cre
Real-Time Settlement							
Payment for Performance*	$1,750	$1,750			-$300	-$1,450	DRP gets pe
Nonperformance Penalty*	-$990	-$240	-$750		$900	$90	LSE is debite
							DRP is debite
LSE Normal Load Balance Credit	$2,400		$2,400				LSE gets bal
Debit	-$2,100		-$2,100				LSE's credit i
Total Received (Paid)	-$21,440	$1,510	-$22,950	$0	$23,100	-$1,360	

DADRP – Recommendations (cont.)

Recommendations to NYSERDA & PSC

- Shift the focus of upcoming outreach and education effort to DADRP participation, while continuing to promote EDRP and SCR. The effort should focus on both DRPs and end-use customers likely to find DADRP useful. DRPs should be brought in to help develop brochures and other materials

NYISO Supports Neenan DADRP Recommendations

- Develop a Program Opportunity Notice (PON) or program to retain performance contractors to conduct audits, advise potential DADRP participants of their options and potential savings, and assist in the development of bidding strategies

DADRP – Recommendations

Recommendations to NYSERDA & PSC (cont.)

- Support a DADRP bid aggregator to facilitate participation in the program by easing bidding and providing convenient, unbiased information to facilitate bid development.

- The Bid Aggregator would:
  - Develop, in consultation with interested DRPs, standardized DADRP products (block size, hours, minimum run time, etc.) to facilitate aggregation of customer bids Provide NYISO market data (prices, trends, indicators) in an understandable format to DADRP participants,
  - Accept, aggregate and submit DADRP bids to defined NYISO buses in each zone (this would address the 1 MW minimum bid problem identified by potential participants)
  - Communicate in a customer-friendly format accepted bid data to participants and advise them when load reduction should be initiated based on accepted bids
  - Settle aggregated DADRP schedules with the NYISO and disaggregated schedules with aggregated DADRP participants
  - Aggregator accepts DADRP bids from all Market Participants on a non-discriminatory basis
  - Aggregator does not compete with DRPs or solicit end-users

Demand Response Governance Changes

At the February 4 Management Committee Meeting it was agreed that:

- Demand Response providers (including Distributed Generation) should be eligible to participate in NYISO Governance in the "Other Suppliers" Sector, provided however that Distributed Generators may be directed to the "End-User" or "Generator" Sectors by the NYISO if their circumstances (size, location, historical and intended use) dictate that they are more appropriately situated in one of those sectors
- Demand Response Providers with 40 MW or less of resources and Distributed Generators with 2 MW or less of resources shall be subject to an annual fee of $1,000 for the year 2004, an annual fee of $2,000 for the year 2005, an annual fee of $3,000 for the year 2006 and an annual fee of $5,000 for the year 2007 and for every subsequent year thereafter